October 31, 2006

We thank those who attended the Intermittency Analysis Project staff workshop on August 15th at the Energy Commission. Three parties filed comments after the workshop: Pacific Gas & Electric, the California ISO, and the California Wind Energy Association. Responses to those comments are below, after a general introduction.

What was presented at the August 15th workshop is preliminary, and more detailed analysis is underway on the 2006 base case and the 2010 Tehachapi case that were the subject of the workshop. The results of that analysis, along with results of the two remaining cases, will be presented at the second and final IAP workshop that is anticipated by January 2007. As a result, some of the questions raised in the comments cannot be answered until the additional analysis is completed.

An interim report will be prepared that summarizes the content of the presentations that were presented at the August 15th workshop. Some of the questions will be referred to the interim report, which will be available in November.

Based on comments at the workshop, a third case has been developed to examine an accelerated 33% renewables level by 2010. The case is not meant to be representative of California policy, nor is it intended to be a real development case. Rather, the case is intended to test whether the California grid can operate with that level of renewable energy and to test the assumptions toward a 2020 33% level. The fourth and final case will focus on the 2020 33% RPS target. Assumptions as well as mitigation strategies and options for California as compared to other world experience in operating with high levels of renewable energy are anticipated.

Finally, we encourage interested stakeholders to participate in the monthly IAP stakeholder calls. Interim results, with assumptions and approaches, will be presented and discussed during these calls as they become available, and we expect the calls may increase in frequency as more results are generated. Contact Kevin Porter at porter@exeterassociates.com for additional details.

Because many of the questions are similar, the questions are grouped by topic.

Questions to be Addressed in the November Interim Report

For any "problems" identified so far by the study team, please describe the nature of the problem and any potential solutions (e.g., increased transmission, increased ramping capability, etc.). (CalWEA)

Many of the basic assumptions in the model are not evident. We would appreciate having a list of all of them, but in particular:

a. What are the assumptions for new non-renewable 2010 resources (what plants are being added – size, type of fuel, type of generator)?
b. What reserve margin does the model assume in 2010?
c. What capacity factor is assumed for new and existing wind projects?
d. What ramp-up rate system limits are assumed, if any? (CalWEA)

The written presentations provide the numerical and statistical results so far, but include little description of the qualitative conclusions. Can you provide a written summary of the conclusions that the study group presently draws from its detailed analysis? In particular, what are the conclusions with regard to the selected periods and "search for extremes"? What probabilities does the study assign to these extremes? What frequency of occurrence? (CalWEA)

An interim report of the presentations given at the August 15th IAP workshop will be released in November that will describe the analysis done to date and the modeling assumptions. The assumptions for new non-renewable 2010 resources are listed on slides 21 and 22 of Davis Power Consultants' presentation and were added to meet reserve requirements, plant retirements and load growth. Overall, 1,795 MW of non-renewable resources were added, all natural-gas-fired, and representing a mix of combustion turbines and combined cycle turbines. The reserve margin is set at 15%, and the capacity factor for new and existing wind projects is assumed to be 37%. No ramp-up system limits are assumed—the IAP project will use confidential individual generating unit ramping capability data.

It is simply too soon to answer the other questions raised. More detailed analysis is underway of the data that was presented at the August 15th workshop, plus there are still two more cases to assess. More definitive results and analysis will be presented at a subsequent IAP workshop that will likely be in the January/February 2007 time frame. Check the Energy Commission website for workshop postings. No final conclusions were drawn at the August 15th workshop, and any qualitative conclusions are premature.

Planning Reserve Margins

How is the level of planning reserve margin affected by the amount of intermittent resources? (PG&E)

The IAP project is setting the planning reserve margin at 15% and will add generation as necessary to meet load growth, plant retirements and planning reserve margins, consistent with projections from the Energy Commission's Electricity Analysis Office (EAO). For the 2010 Tehachapi scenario, Davis Power Consultants' presentation on August 15th noted that 1,795 MW of non-renewable resources were added to meet load growth, retirements, and planning reserve margins.

RPS Objectives

What objectives is the 33% RPS goal intended to satisfy? (PG&E)

Governor Schwarzenegger has indicated strong support for an RPS goal of 33% by 2020, referring to renewables as the cornerstone of the state's energy and environmental action plans. The *2004 Integrated Energy Policy Report Update* recommended supporting the Governor's goal, and stated that ambitious RPS goals for the post-2010 period are needed to "maintain the momentum of renewable energy development, expand investment and innovation in technology, and drive costs down for renewable energy."

California's RPS is at the forefront of the strategy to diversify California's electricity system, protect the environment, and keep California on the leading edge of new technology development and use. A diverse energy supply helps to stabilize prices and reduce California's vulnerability to high natural gas prices, while renewables are also an essential strategy in the state's efforts to meet the Governor's aggressive greenhouse gas reduction goals.

In his response to the 2003 and 2004 Integrated Energy Policy Reports, the Governor stated that California's renewable energy goals signal "our willingness and intent within the State and to the other Western States that California is committed to energy diversity." In addition, the Governor directed the Energy Commission to evaluate the 33% renewable goal to ensure that "renewable assets will be accommodated efficiently into electricity grid operations." The IAP cases looking at the 33% renewable penetration level supports this directive.

Integration Costs

What are the incremental costs of increasing the RPS goal, including transmission, maintenance, operational reserves, and necessary day ahead dispatching, and mitigation of intermittency? How does cost impact RPS objectives? (PG&E)

The IAP project will assess the impact of many of these items such as transmission, reserves, and mitigation, but it will not measure the costs for integration, maintenance or dispatch costs. That is beyond the scope of the IAP and will likely require utility or California ISO involvement in a follow-up project to answer these questions.

Reliability Thresholds and Saturation Point for Intermittent Renewables

When do we know when there are too many intermittent resources for different system load levels? Further analysis to study impacts of high renewable penetration on system ability to meet frequency response during system disturbances would be insightful (PG&E)

Is the 33% goal feasible, that is, can the CA ISO and the LSEs reliably and cost-effectively dispatch and regulate the system with this level of renewable generation? (PG&E)

Based on the current model results of intermittency impact on the system, how much and where does quick-response or other type of generation or load-response need to be added to maintain system reliability? (CalWEA)

What renewable resource mix will help increase penetration? What proportion of intermittent vs. non-intermittent and solar to wind is operationally feasible? (PG&E)

A goal of the study is to determine where the system breaks - but that is not defined (California ISO)

Does the study group have a decision rule for concluding whether the assumed resources in 2010 are able to manage intermittency impacts? Is it possible to identify a "break point" in terms of the statistics reported in the slides? (CalWEA)

This or a future study about the feasibility of higher RPS goals should provide criteria for determining whether we have reached a saturation point for intermittent resources. Examples of operational factors to consider when developing criteria include: (1) nuclear power, other renewable generation, and/or out of state coal is curtailed to accept intermittent resources; (2) dump power (hydro spill); (3) collapse of spot prices over long periods; (4) large increases in regulation requirements and need for conventional resources (e.g., CTs); or (5) when large amounts of back-up reserves and/or high intermittency mitigation cost (e.g., pumped storage) make overall costs too prohibitive. Ultimately, it needs to be determined under what system conditions and renewable resource mix, including levels of intermittency mitigation, are different levels of renewable penetration feasible and reasonable (PG&E)

The second IAP workshop will address many of these questions. In general, the primary aim of the IAP project is to determine what are the issues related to the resource mix and the penetration levels of intermittent renewable energy, and whether the California grid can operate reliably with higher levels of intermittent renewable energy generation. Important indicators whether there is enough maneuverable generating capacity and ramping capability to follow changes in load and in intermittent renewable energy generation. Other items of interest include how the California grid responses to stress conditions such as minimum load, and whether potential mitigation and operating options help manage periods of grid stress and help incorporate higher levels of intermittent renewables. This part of the analysis is just getting underway, and results will be available by the second IAP workshop (Jan/Feb 2007).

Regarding what renewable resource mix will increase penetration, the renewable resource mixes are designed to reach the 20% and 33% renewable energy targets and are intended to develop intermittent and non-intermittent resource mixes that can be operationally feasible. Similarly, while the IAP project will test whether the levels of wind and solar in the four scenarios are operationally feasible, the IAP project will not go further and test higher and higher levels of wind and solar until it is not considered operationally feasible.

Renewable Resource Availability

Are there sufficient resources economically available in the market to satisfy a higher RPS goal? How much renewable power must be imported to meet a 33% target? How much transmission must be reserved for imported renewables? To what extent is a higher RPS goal increasing the price for the same amount of renewable supply? (PG&E)

It is very important that the results of the IAP study reflect the constraints of the California Power Grid. An example is the limitations of the hydro system to provide regulation services during the heavy spring runoff period. The units are running at full output levels cannot move up and down to provide regulation capability. The hydro units also have limited reservoir storage and the water in the reservoirs is usually depleted by September or early October. So the hydro system is not available for regulation services in the 4th quarter until the rains start and the reservoirs recover (California ISO)

The CEC prepared a renewable resources mix for each scenario and determined there were sufficient enough in-state renewables to satisfy a 33% level of renewable energy by 2020. The IAP project is focused on in-state renewables and the infrastructure that may be necessary to support in-state and out-of-state renewables and is not evaluating imports from out-of-state renewable energy sources. Overall, it is not in the scope of the IAP project to determine whether the 33% goal is feasible. It is a target, resources are available to achieve the goal, and the focus is now on how best to manage the impacts with the available mix of resources.

Concerning the California ISO's concerns on hydro, we appreciate this information from the California ISO and will incorporate it into the modeling.

Spot Price Volatility

What are the impacts of intermittent resources on volatility of spot power process? (PG&E)

Results suggest need for further analysis to quantify impacts (opportunity costs) of increased price volatility due to intermittency and impacts to operational flexibility (PG&E)

The IAP project will not address the issue of increased price volatility or of opportunity costs, but a primary aim of the project is to consider whether there is enough flexibility in the California grid to incorporate higher levels of intermittent renewable energy generation.

Renewable Transmission Benefit Ratio

The Renewable Power Flow Impact Analysis quantified the benefits of current levels of intermittent resources on the grid. However, it is unclear to PG&E how the Renewable Transmission Benefit Ratio would be used. Is RTBR intended to be another metric for least-cost best-fit selection of RPS bids? Since generally, the development of renewable resources (except distributed solar) are constrained to specific geographic locations, PG&E suggests the focus should be on the costs and benefits of transmission upgrades needed to bring renewable power to the load center (PG&E).

The RTBR is similar to the least-cost best-fit process of selecting RPS bids. The RTBR measures the benefits (or negative impacts) of renewable energy projects on the grid. The renewable energy projects are prioritized by the benefit of each renewable energy project for improving system reliability. Next, the transmission and renewable construction costs are calculated to get a composite energy rate for each renewable energy project. After that, a priority list of renewable energy projects can be developed that takes into consideration all of these factors, as well as location and temporal factors, to produce the least-cost best-fit resource alternatives that can meet the penetration targets and improve system reliability. Davis Power Consultants' August 15th presentations reviewed the methodology in detail.

Concerning transmission upgrades, transmission will be added consistent with the transmission plans of the California ISO and California's utilities (e.g., Tehachapi, Imperial Valley) and with maintaining the present level of reliability. The transmission cost analysis will be completed by the next IAP workshop and will be in the final report.

Solar and Wind Resources

The interim results show that solar is complementary to wind production profiles. While this may be true using hourly daily profiles, solar production does not mitigate the adverse impact of wind generation uncertainty or its hourly generation volatility. Also, because the actual mix of renewable resources will be different than that assumes in this analysis, the true impacts of the RPS goals should be estimated for different mixes of renewable resources. Operational and cost impacts of incremental amounts of renewable generation need to estimated by technology rather than presented as a block and combined with load impacts. Clearly identifying the cost and operational feasibility issues by technology is needed to understand the feasibility and cost of a higher RPS goal for different renewable resource combinations (PG&E)

Does the study group view the 1-hour, 1-sigma wind-and-solar impact for 2010 of 48 MW as being significant? In general, has the study already identified impacts it considers to be significant? (CalWEA)

Does the study account separately for existing renewables and the renewables that are added to reach 20% in 2010? Is it possible to measure the incremental impact of the 20% goal? The results that compare load to "load minus wind minus solar" do not appear to account for the impacts of existing intermittent resources. If not, is it correct to say that the incremental impact in 2010, relative to business-as-usual, in terms of the 1-hour 3-sigma result (p. 74 of the GE slides) is 99 MW (i.e., 144 MW 2010 impact less 45 MW as the 2006 impact)? While the overall results will not change, it may be important to understand what portion of the impact is attributable to the additional intermittent resources (CalWEA)

The information on solar hourly profiles being complementary to wind hourly profiles is merely an observation, not a finding or interim result. No assessment was drawn or meant to be implied that solar will mitigate wind impacts.

The grid impacts of wind and solar on a sub-hourly basis in the 2006 and 2010 Tehachapi scenarios are being assessed now. Future results of the IAP project will break out the solar and wind impacts. On a separate note, the IAP study is meant to address the operational impacts of intermittent renewable generation and will not address cost impacts.

The IAP team is not prepared to consider the 48 MW figure as significant or not, given the early stage of the analysis, nor is the team prepared to identify impacts that are considered significant. That part of the analysis is just underway. The IAP project does separately account for existing renewables versus the incremental renewables that are added to reach 20% by 2010, and CalWEA's interpretation that the incremental hourly impact in 2010 is 99 MW is correct.

Wind Forecasting

Impacts of forecast errors on dispatch costs were not quantified in the analysis. It would be instructive to quantify unit committed changes/costs between perfect forecasting and no forecasting of intermittent resources, which may provide insight on how much back-up power may be needed for intermittent resources. The gap between a wind forecast with a bias down and "actual" wind could be used as a proxy for over and/or under forecast from which unit commitment costs could be estimated (PG&E)

Does AWS TrueWind assign a deterministic generation profile for each wind location? If not, for a given wind location and hour, please describe the statistics (mean & variance) of individual project output vs. combined project outputs. The 'spatial pattern' presented on page 13 of the GE part 2 presentation is interesting, but does not appear to address this question directly. For example, what is the forecast error for individual wind production vs. aggregate wind production across given hours? (CalWEA)

There are 36 wind sites in Tehachapi that are modeled in the 2010 Tehachapi case. AWS TrueWind uses a combination of deterministic and statistical methods to derive wind output profiles for each location. Each site is modeled separately in the production cost modeling and in the quasi-steady-state simulation that is underway currently. However, because this is a study of the state-wide grid impacts of intermittent renewables, the statistical analysis of the wind production at Tehachapi is aggregated. What is presented on slide 13 is the generation profile of each wind location at Tehachapi and the aggregate of all of the individual wind generation profiles. More information on wind forecasting will be provided in the final report. In addition, the Energy Commission has various other projects related to wind forecasting. Contract Dora Yen (dyen@energy.state.ca.us) of the Energy Commission for further details.

Concerning PG&E's question on unit commitment, the IAP project is focused on state-wide grid impacts from intermittent renewable energy generation and will not delve into the individual changes or costs in unit commitment decisions. The IAP project will report results on changes in overall unit commitment costs from no wind forecasting, wind forecasting and perfect forecasting, as well as overall wholesale market costs (or gains) from adding intermittent renewable energy generation; revenue increases for wind and solar generators; revenue increases for other generation; and load payment impacts.

Ramping/Regulation

The preliminary conclusion of the 2010 case suggests that that system ramping rates and regulation needs are not significantly affected with large penetrations of intermittent renewables. This does not comport with CAISO estimates of a significant increase in ramping need with large penetrations of wind. The study also does not estimate the additional amount of regulating resources in MW and MVAR needed to integrate the amount of intermittent resources. For the results to be useful, we will need an estimate of how much regulation service is required with each level of penetration, so we can have an idea of the hardware necessary to support each level (PG&E)

I am concerned that the interim results find that no significant problems for the 20% renewables case. The CAISO experienced operating issues this spring with the current amount of wind generation installed on the system. The area of greatest concern is the large amount of wind generation that is produced at night during light load periods. There was not sufficient load to use all this power nor could we export it adjacent control areas. All other units were either off line, set at block loading levels that could not be changed or were already at minimum production. This will be an increasing problem with the large amount of new wind generation we expect to be built in the Tehachapi area (California ISO)

The presentation for the 2010 Tehachapi case show that there are some concerns with minimum load periods, a result consistent with the California ISO's stated concerns. Increased hourly variability was found with wind and solar, and it was found that 6% of hours with wind and solar result in net load less than the minimum load without wind and solar. The presentations also noted a tendency to under-forecast wind production, and that was compounded during light load periods. These and other issues will be more closely investigated as additional analysis using sub-hourly data is completed on the 2006 and 2010 Tehachapi cases, and as work on the final two cases begins. Please also note that the information in the August 15th presentations is preliminary—much more definitive findings and results will be presented at the second IAP workshop and in the final report. The analysis of the sub-hourly data is underway, which is why regulation impact results were not presented at the August 15th workshop. Regulation impacts will be presented as part of each case.

NERC/WECC/CA ISO Planning Standards

Given that the power flow cases show potential problems and have difficulty finding a feasible solution, a concern is that the GE production simulations may not satisfy NERC/WECC/CAISO planning standards without major infrastructure reinforcement. Further studies will need to investigate not only power flow but also stability analysis (PG&E)

If dispatch scenarios from GE production simulations satisfy planning standards but dispatches in power flow cases do not, it is an indication that real time dispatch will need to be limited to those scenarios that satisfy standards. We will need to decide if such a limitation in real-time operation is acceptable (PG&E)

The power flow results for the 2020 case were preliminary and most of the issues raised at the August 15th workshop have been addressed, thanks in large part to meetings between the IAP team and utilities such as PG&E. The power flow results for the other three cases meet planning standards. We agree with PG&E's concern about production simulations based on load flows that do not comply with NERC, WECC and CAISO planning standards, and would not run a simulation in that instance. Follow-up work after completion of the IAP project will need to consider real-time operations.

Modeling Assumptions and Data Availability

At the workshop, it was stated that the power flow modeling assumed reactive power (VAR) consumption for wind projects, which is inconsistent with FERC and WECC standards for new turbines. With the correct assumptions, is there a VAR support problem? (CalWEA)

If it is not confidential, can you provide the 2010 data set being used in the production cost modeling? If confidential, please post to WECC (CalWEA)

The data is confidential. However, the CEC plans to prepare consistent 2010 and 2020 datasets for WECC distribution and dissemination at the conclusion of the IAP project.

Concerning the question about VAR consumption, the modeling assumed a 5 to 10 percent VAR range. The power flow dispatch determines the VAR generation that needs to be injected or extracted from the wind site. The VAR limits are being adjusted to be consistent with WECC standards. However, VAR support problems do exist on the grid with the existing fleet of wind turbines in California.